Carbon Mitigation Unit Costs of Building Retrofits and the Scope for Carbon Tax, a Case Study

Royapoor M [a]; Du H [b]; Wade N [a]; Goldstein M [b]; Roskilly T [a]; Taylor P [a]; Walker S [a]

*Corresponding author email: Mohammad.Royapoor@newcastle.ac.uk; Tel. +44 (0)191 208 6169

[a] School of Engineering, Newcastle University, Newcastle upon Tyne, NE1 7RU
[b] Department of Mathematical Sciences, Durham University, Durham, DH1 3LE

Abstract

Energy and environmental data is collected from 5 tower blocks each containing 90 apartments to create two representative calibrated energy models. Three towers (heated by individual natural gas boilers) characterise medium (137.3 kWh/m2/yr.) and two (heated by electrical night storage heaters) characterise low (75.4 kWh/m2/yr.) thermal demands when benchmarked against actual UK domestic portfolio. Across 2020-2040 time horizon, an uncertain landscape is presented by 12 fuel carbon intensity and 14 economic scenarios in order to examine building fabric upgrade, without or in conjunction with centralised CHP engines, GSHP and biomass boilers in the case study towers. Out of 18 retrofit options examined, 7 or 8 solutions (under annual fuel price rises of 2% or 5.2% respectively) can provide lifetime CO2e mitigation at unit costs that fall below the upper bounds of carbon capture and storage technologies (US$143/tCO2e). If carbon taxation were to be used to enable full recovery of retrofit capital expenditure with no government subsidy, the lowest tax level observed belongs to a transition to centralised biomass from decentralised natural gas boilers requiring US$111/tCO2e (in 2020), while deep retrofits (i.e. plant and fabric) require much more punishing carbon taxes with 2020 figures ranging from US$233/tCO2e to US$1665/tCO2e.

Keywords

Low carbon heating, energy supply decarbonisation, building retrofit, market and policy uncertainty, Carbon Tax.

Highlights

- Unguided markets cannot produce price signals for heating decarbonisation
- Decarbonising heating sector can achieve similar unit costs ($/tCO2e) as CCS
- Robust fuel carbon content can inform least-cost heating decarbonisation routes
- Moderate carbon taxes cannot enable CapEx recovery of low carbon heating solutions
- Centralised Biomass and GSHP recover their CapEx only via government subsidies

1 Introduction

Severe housing shortage following WWII and post war development of modular design techniques led to the construction of a large number of tower blocks in Europe. Together with the need to house a growing post-war population, high-rise buildings offered a fast, simple and comparatively cheap replacement of the damaged domestic housing stock. Towers with prefabricated elements and modular construction became an integral part of the 20th century modernist movement which incorporated technological advances into underlying design principles with the aim of modernising not only the housing stock, but also society [1]. What remains of post war high rise buildings rank poorly against current building performance criteria. These towers form the hard-to-treat building stocks that the Commission of European Union recast directive [2] expects member states to transform into very low energy buildings. The UK Government is also currently seeking low carbon heating solutions and heat networks [3] to decarbonise space heating in the domestic sector, which in combination with the industry and transport sector is expected to achieve 50.6% carbon reduction over 2020-2040 time span (see 2.2). This work utilises extensive field data and occupant engagement from five 15-storey tower blocks to develop two representative calibrated models of [a] three towers heated via individual natural gas boilers and [b] two towers heated via individual night-time electrical storage. Calibrated model predictions are benchmarked against actual UK housing in order to derive 'scalable' techno-economic results of 18 retrofit options based on [a] upgrading the tower fabrics in isolation or in combination with [b] centralising the supply of thermal demand using ground source heat pumps, natural gas fuelled CHPs or biomass boilers. The inevitable landscape of techno-economic uncertainty is treated as follows:

a) Fuel decarbonisation pathway uncertainty: A combination of 3 grid electricity (containing 50, 75 and 100gCO2e/kWh) and 4 natural gas (containing 0, 5, 12.5 and 20% of bio-fuel) fuel characteristics. These are assumed achieved by the end of 5^{th} UK carbon budget (2032) resulting in 12 future primary fuel decarbonisation scenarios to inform retrofit carbon savings.
b) Future economic landscape uncertainty: Discount rates of 2% to 8% to represent the price of time in the assessment of Net Present Value of each retrofit option as well as historically-driven moderate (2%) and high (5.2%) annual fuel price rises. These assumptions result in 14 future financial scenarios to assess the extent to which each retrofit solution can recover the capital expenditure.

These techno-economic results are used to provide the following comparative benchmarks:

a) Identification of retrofit solutions that can deliver carbon reduction in line with 2020-2040 UK emission targets.
b) In order to illustrate a broader least-cost route to economic decarbonisation, the standardised carbon abatement ability of all retrofits (i.e. tonnes of CO2e saved per unit of $ investment) is benchmarked against the best current economic alternatives (i.e. carbon capture and storage). This allows identification of economic sectors that can deliver most carbon abatement per unit expenditure.
c) The level of carbon tax obligations which can enable retrofit solutions to fully recover their capital expenditure (CapEx) within a typical 20 year lifetime set against the idealised energy-economy-climate model carbon tax recommended by Intergovernmental Panel on Climate Change.

2 Literature review

2.1 Low carbon retrofits

Field studies and evaluation of sustainable retrofit opportunities particularly in high-rise buildings have so far been a rather neglected area [4]. Ownership type (i.e. private, corporate, institution or governmental) has been found to have the most impact on the way retrofit decisions are made [5]. Retrofitting is often more economical and has less environmental impact when compared to complete demolition and rebuild [6, 7]. Arriving at sustainable retrofit options for clusters of social housing is currently of great interest to the UK government, in particular in light of its ambition to fund pioneering local low carbon heating solutions [3]. Social housing towers in the UK have historically suffered a combination of structural issues, poor thermal performance and chronic lack of investment that not only in the public but also privately owned sector has led to low rates of retrofits principally aimed at fuel preservation. In a 2016 progress report to the UK Parliament it was highlighted that UK carbon emissions had been reduced by 38% compared to the 1990 baseline, yet building sector carbon emissions have remained constant since 2012 [8]. This is partly due to uncertainty in return on investment (ROI) as well as substantial upfront cost, that remain the main barriers in particular to more expensive green retrofit measures [9, 10]. M. Folie et al. conducted a study of 30,000 houses under the Weatherization Assistance Program (WAP) and stated that despite an average monthly energy reduction of 10%-20%, the ROI was economically uncompetitive to investors [10]. A number of recent papers have offered optimisation tools to enable financial assessment of retrofit measures [11-14] and also acknowledge that fiscal evaluations fail to capture broader retrofit benefits such as improved comfort and health, environmental standard compliance and increased building durability. UK zero carbon homes (a target for all new homes by 2016, later abandoned by UK government) set a combined heating and cooling sum of 39 kWh/m2/year corresponding to 14 kg CO_2e/m^2/year in low rise apartments as a feasible goal, while the zero carbon hub cost analysis estimated the cost of the aforementioned zero carbon homes by 2020 to be an additional £1900-£2000 per apartment (accounting for falling cost of low carbon solutions) [15]. However the economics of deep retrofit has always suffered from hugely uncertain medium and long term economic landscapes. As a result net present value (NPV) has been the most widely used indicator for investors since pronounced future risks and uncertainties can be realised by assigning larger discount rate components. This results in NPVs being highly sensitive to discount rate selection, with a broad range of values applied to reflect specific institutional or economic perspectives. Discount rate itself is firmly rooted in the expectations of private sector investors and the concept of lost opportunity. Within EU and North American economies, recommendations range from 2% to 8% [16] that form a major source of discrepancy in economic appraisals [17].

2.2 Primary fuel decarbonisation

The UK pursues overall carbon emission reductions of 8.6%, 23.3% and 11.5% over its 3rd to 5th carbon budgets (equivalent to a reduction of 57% from 1990 levels by 2030) [18]. Thereafter the only existing target enshrined in legislature is a 2050 reduction of at least 80% (from 1990 levels)[19]. Spread at a linear rate, this equates to an annual carbon reduction of 1.28% over the 2032-2050 horizon. Hence across the 2020-2040 window the UK economy is expected to achieve a carbon reduction of 50.24%. The most notable missing piece in informing effective and low carbon building retrofit is the potential yet profound effect that policy-related decarbonisation of primary energy supplies (grid electricity in particular) will exert. Rapid decarbonisation of electricity will shift the green retrofit credentials from primary plant overall efficiencies to operational carbon emissions. A robust method of reporting operational greenhouse gas (GHG) emission from buildings in a consistent and comparable way is effectively missing [20]. Consistent GHG reporting frameworks first allow characterisation and benchmarking of existing stock in need of retrofit, and later identification of green retrofit technologies where upfront investments yields the greatest carbon reductions. Equivalent carbon figures of UK grid electricity is heavily aggregated (from nuclear, coal, gas and renewable generations) and the UK government offers an uncertainty range of ±2%, describing upper and lower bands for equivalent carbon[21]. The UK Committee on Climate Change (CCC) has stated that UK grid electricity has the potential to achieve a carbon intensity of generation of around 50-100 gCO2e/kWh by 2030. The latest 2030 scenarios aim towards the upper end of this range, reflecting delays in nuclear and carbon capture and storage (CCS) projects as well as an improved understanding of the system costs of reaching 50 gCO2e/kWh by 2030.

Natural gas decarbonisation without imposing consumer appliance modification presents a greater challenge. A bio-methane mix is the only readily-deployable solution, with a narrow scope of 5% to 20% of the total mixture of natural gas supplies which is imposed to ensure existing appliance fuel compatibility. Whilst hydrogen injection shows similar potentials [22], it is not considered here as the chosen gas-powered CHP and boiler plants can only operate using natural gas with up to 20% bio-methane mixture. The most plausible way of constructing future gas scenarios from techno-political documents that contain potential decarbonisation pathways for natural gas supplies would therefore be via bio-mix injection as stated in recent UK Parliamentary notes [23], with the most probable rate of carbon reduction being in overall agreement with aforementioned UK government's 3rd, 4th and 5th carbon budgets (Fig 1). Fig 1 shows that UK electricity carbon content has declined exponentially since 2015, while natural gas carbon content has remained constant.

Fig. 1

Wood pellet biomass fuel carbon content has been published for the UK government since 2014, with no discernible time-related pattern (11.8, 13.2, 13.1, 12.7 and 15 gCO2e/kWh over 2014-2018). As carbon content of biofuel is mostly a net lifecycle carbon product arising from the fixed hydrocarbon nature of biomass, CO2e of biofuel can be taken as relatively static. An average of 13.2 gCO2e/kWh (for the period 2014-2018, error band of [-1.3, +1.9]), is used for this work's biomass carbon content.

2.3 Carbon taxation

Among market and regulatory mechanisms, carbon pricing is viewed as an effective instrument to incrementally guide free markets towards a rapid decarbonisation path, while accounting for heterogeneity of emitters, avoiding transboundary carbon leakage and rebound effect and retaining the consumer's autonomy of choice [24]. The World Bank defines carbon taxes as initiatives that put an explicit price on GHG emissions (i.e. a price expressed in US$/tCO2e) [25]. The Intergovernmental Panel on Climate Change (IPCC) presented 34 scenarios to enable carbon containment to 430-480 ppm CO2 by 2100, leading to respective lower and upper quartiles of carbon price equal to US$37-67/tCO2e (in 2020) and US$127-305/tCO2e (in 2050) [26]. While political economists use emmiter taxation to internalise a global warming externality, carbon pricing was noted in a report to abait the inflow of CO2 without addressing the existing concentration (stock) [27]. The report concludes that carbon prices have demonstrated potential to reduce emissions relative to business as usual trajectories, albeit with marginal rather than deep changes. Currently

CCS remains the most economically competitive abatement tool with global cost estimates ranging from US$38 to US$143/tCO2 [28], while a more recent development reports sub-surface based mineral CCS at US$25/tCO2 [29] in the context of northern Europe and the US.

3 Description of case-study buildings

The case study buildings are five 15-storey brick-clad towers built in the 1960s, of which three have natural gas supplies enabling central heating systems and gas cooker use (type 1), and two have only electricity supply and are heated by electric storage heaters charged using off-peak electricity (type 2). Originally built with brick and block infills, both tower types had double glazing upgrades in the early 2000s. Additionally the type 2 towers were retrofitted with both insulated external cladding and internal wall insulation, leading to a 55% improvement of external wall thermal resistance when compared to type 1 towers (see table 1). Each tower contains a total of about 30 one- and 60 two-bedroom flats of uniform layouts. Electrified towers are oriented 30° east of due south and gas heated towers are oriented 7° east of due south (Fig. 2). Table 1 also shows the 2010 UK fabric U-Values [30] required if a building fabric upgrade is undertaken.

Fig 2:

Table 1: Existing and proposed fabric thermal values of 5 case-study towers

	Type 1	Type 2	Required U-Values for tower fabric upgrade
Heating and DHW supplies	Natural Gas boilers	Night storage electricity	-
Number of towers	3	2	-
Total number of dwellings	265	174	-
Year completed	1961	1965	-
External wall U-value ($W/m^2/K$) [1]	1.136 [2]	0.504[3]	0.30
Internal floor U-value ($W/m^2/K$) [4]	0.493	0.493	-
External floor U-value ($W/m^2/K$) [5]	1.366	1.366	0.25
Roof U-value ($W/m^2/K$) [6]	1.707	1.707	0.20
Double glazing ($W/m^2/K$) [7]	2.59	2.59	2.0

Notes:
[1] An earlier invasive survey had found evidence of cavity insulation in both building types but was unable to determine its thickness. 20mm (type1) and 30mm (type2) produced the closest building calibration results against actual data. 1.8% cold bridging allowed as outlined in section 3.
[2] (a) 83% masonry with 100mm brick cladding, 55mm airgap, 20mm mineral fibre, 100mm medium density concrete, 15mm plaster and (b) 17% PVC subsurface with 28mm PE insulation.
[3] 100mm brick cladding, 45mm airgap, 30mm mineral fibre, 100mm medium density concrete, 40mm Polyurethane insulation, 15mm plasterboard.
[4] 250mm cast concrete, 5mm insulation, 7mm screed, 3mm carpet underlay, 3mm carpet.
[5] Strip foundation with Polythene DPM, 125mm precast concrete, 38mm screed
[6] 15mm plaster, 10mm insulation, 250mm cast concrete, 2mm roofing felt, 10mm Asphalt.
[7] 3mm clear glass, 6mm air gap, 3mm clear glass.

All towers are identical in having a net footprint of $420m^2$ and net internal space of $5685m^2$ (of which 84% is heated). External walls (with a gross area of $4451m^2$) are 27% glazed. Two extensive sets of thermal imaging in winters 2015 and 2016 demonstrated a fairly uniform fabric thermal property across the brickwork (type 1) and brick claddings (type 2). However cold bridging exists from the uninsulated concrete floor slabs that penetrate the insulated external envelope of all towers resulting in the external surface temperature of concrete to be 3°C to 5°C warmer than the adjacent wall (Fig. 3). Fabric heat loss particularly in these tall buildings which are exposed to uninterrupted wind streams and self-induced upward convective air currents, together with reports of rain penetration and condensation issues build a strong case for external fabric upgrade.

Fig 3:

To parameterise and calibrate an EnergyPlus building model, monitoring equipment was deployed in all 5 tower types (Table 2). Additionally a total of 30 residents completed a comprehensive social science questionnaire which investigated their views on the sustainability, life quality within their living environment, preferred retrofit technologies and levels of refurbishment interventions deemed acceptable.

Table 2: monitoring equipment and deployment purpose.

	Freq.	**Instrument**	**Location**	**Duration**	**Purpose**
Water	5 sec	Ultrasonic flow meter (Katronic KATflow 230)	1 type 1 tower 1 type 2 tower	2 weeks per deployment	- Constructing occupancy profiles - Estimating DHW consumption
Electricity	60 sec	CT clamp-on or pulse-counting sensors	20 distribution boards [2]	6 - 9 months	- Measuring apartment level usage profile - Model parameter input
Electricity	60 sec	Substation monitoring (by local electricity distributor)	transformer substation (both tower types)	9 months	- Measuring aggregated electricity demand at tower level - Model calibration
Natural Gas	60 sec	Pulse counting proprietary sensors	2 incoming gas meters (type1)	9 months	- Establishing the pattern and magnitude of gas consumption - Model calibration
Temperature and Humidity	10 min	Proprietary sensors	Bedroom and living room of 20 apartments [1]	6 - 9 months	- Model target temperatures
Natural gas / electricity	Daily	Manual recording by occupants	20 apartments [1]	6 - 9 months	-Sensor data verification - Model parameter input
Climatic data [3]	Hourly	Rooftop weather station	Local station [2]	9 months	Model calibration

Notes:
[1] Type 1= 9 apartments; Type 2= 11 apartments.
[2] Sourced from a weather station [31] positioned within a 2km radius of both tower types.

4- Method

4.1 Energy model calibration

EnergyPlus is a first-principle based building energy modelling tool that has been developed over several decades by the US department of energy in close collaboration with research institutions. EnergyPlus uses fundamental heat and moisture balance equations to complete building thermal behaviour whereby a multiplicity of differential equations within integrated modules are solved iteratively to produce a convergence that honours parameter inputs and achieves target temperatures using three integrated module platforms: [a] surface and [b] air heat exchange and [c] HVAC simulation manager. EnergyPlus is widely used and audited by the international research community to examine HVAC and fabric design [32] and optimisation [33, 34], forecasting, carbon assessment and resource management at building level and urban scales [35, 36].

Two EnergyPlus models representing types 1 and 2 towers were parameterised with data outlined in table 2 and incrementally improved to satisfy ASHRAE Guide 14 acceptance criteria [37] for energy model calibration using the main statistical indicators of errors, mean bias error (MBE) and coefficient of variation of the root mean squared error (CV(RMSE)) as given by:

$$MBE = \frac{\sum_{i=1}^{N_i}(M_i - S_i)}{\sum_{i=1}^{N_i} M_i} \qquad [1]$$

$$CV(RMSE) = \frac{\sqrt{\sum_{i=1}^{N_i} [\frac{(M_i - S_i)^2}{N_i}]}}{\frac{1}{N_i}\sum_{i=1}^{N_i} M_i} \qquad [2]$$

Where M_i and S_i are respective measured and simulated data at instance i, and N_i is the count of the number of values used in the calculation. ASHRAE Guide 14 considers a building model calibrated if hourly MBE values fall within a ±10% band and hourly CV(RMSE) values fall below 30% acceptance threshold [38]. Absolute errors are generated using expression 3 as recommended by [39]:

$$\varepsilon_i = M_i - S_i \qquad [3]$$

Where ε, M and S represent error, measured and simulated values at instance i.

4.2 Primary plant efficiencies

The design of centralised hydronic systems and associated control strategies presents a multitude of optimisation challenges [40] that can expand the scope of this work to unmanageable levels. In order to create realistic boundaries, an assumption is made that all primary plants perform at the upper quartile efficiencies of actual field studies reported in scientific literature (replacing manufacturer's claimed efficiencies). Seasonal performance factor (SPF_{H2} and SPF_{H3}) was found to be the most relevant metric [41] for GSHP that are simulated using an SPF of 3.5 with the treatment of geothermal array performance as outlined in Appendix A. Bio-mass boiler efficiencies vary widely with fuel type, combustion equipment and operating conditions [42], and actual efficiencies of biomass boilers have been found to be notably smaller than claimed manufacturer's values [43]. The upper quartile efficiency of 75.5% is used for this study, based on newly commissioned central woodchip/pellet biomass plant efficiencies of 71.5% to 76.75% [43].CHP system efficiencies are similarly sensitive to size, cycling and part load duties and are represented in this work with an overall efficiency of 84.5% derived from the upper quartile of observed values (table 3). Type 1 gas boilers were assigned an overall efficiency of 81.8% with progressive annual improvement of 0.2% (reported in table 6C of UK energy fact files [44]) to account for gradual upgrades of existing individual boilers. Type 2 electric storage heating seasonal efficiencies remain at a constant value of 0.98.

Table 3: Actual primary plant efficiencies informing the comparative analysis.

	Mean values from field trials						Upper Quartile
GSHP SPF[1]	3.93	2.6	2.5	3.3	3.03	3.2	3.5
Biomass boilers (η) [2]	55	90	69	59	74	68	75.5
CHP engine (η thermal)	38	43	37	53	44	41	
CHP engine (η electrical)	45	36	48	30	35	36	
CHP engine (η overall)	83 [3]	90 [4]	85 [5]	83 [6]	79 [6]	77 [6]	84.5

[1] Mega study results outlined in table 14 [41]

[2] Measured efficiencies derived from field measurements of a total of 6 pellet biomass boilers [43]

[3] Year-long Field values of 4.2 MWe unit [45].

[4] Lab based results of 816 kWe unit [46].

[5] lab based results of a 2kWe unit [47].

[6] Reported values of 100kWe/800kWe and 3MWe units [48].

4.3 Economic appraisal

To examine future economic uncertainty and the impact of discount rate, the full range of 2%-8% at 0.5% increments was used to construct NPV using:

$$NPV_{i,N} = R_0 + \sum_1^N \frac{R_t}{(1+i)^t} \qquad [4]$$

Where R_0 is the initial investment, instances 1 to N are the annual savings achieved across an expected investment lifetime (N) with i representing the discount rate (higher discount rates assign lesser value to money earned in future). A typical plant life expectancy of 20 years is assumed with no residual value at year 20 (i.e. the decommissioning cost would equal salvage value of recyclable components). The starting price for gas and electricity were taken to be the average of 7 major UK suppliers, with gas costing 4.77 ¢/kWh, and peak, night-time and export electricity costing 17.2¢/kWh, 6.45¢/kWh and 0.00052 ¢/kWh. These values are projected across a 2020-2040 horizon based on a historically-driven consumer price index linked inflation. An average consumer price index (CPI) of 2.0% (observed over 1998-2018 historical timeline [49]) represents a moderate 2020-2040 fuel price rise and the highest observed annual CPI of 5.2% (observed in the last decade) represents an extreme case. GSHP and biomass subsidies committed to by the Office of Gas and Electricity Markets (Ofgem) [50] are treated similarly. The Chartered Institute of Building Services Engineer's best practice recommendation was used to inform hydronic system design [51]. Costing of centralised distribution pipework and upgrading of electrical storage heaters to water-based radiators were conducted by a local contracting firm, while tower fabric upgrade was costed using a quantity-based elemental method that remains the most accurate site and project-specific costing tool in construction [52].

4.4 Carbon analysis

To maintain consistency, unit equivalent carbon content of all fuels (gCO2e/kWh) are based on released UK government data [53] with ±2% forming the uncertainty band (see 2.2). Future grid electricity projections are based on the reported 2018 figure of 283 gCO2e/kWh (forming the mid-value) with ±2% of this value creating lower and upper starting points in 2018. An exponential decline of the form outlined in expression 5 (x: time; Y_e: equivalent carbon content of grid electricity) brings this value to 75±25 gCO2e/kWh in 2030 (as stated in section (e) of [54] to be UK's grid carbon intensity in 2030). The exponential decline reflects the faster rate of decarbonisation in the 2020s and a slower path closer to 2030s as outlined in chapter 2 of [55]. The exponential form is also the best fit to follow historical evidence of grid electricity decarbonisation from 2015 onwards. This declining trend arrive at a 2040 mid-value of 22± 12 gCO2e/kWh (Fig. 1). Note that the continuation of decline post 2030 is to reflect power sector decarbonisation targets beyond 2030 (as outlined in chapter 1 and further distilled and illustrated in fig. B 4.2) of [54]). A declining CO2e trend for electricity in the run-up to 2050 has also been supported by research examining the wider European context [56, 57].

$$y_e = 0.3509 \times e^{-0.12x} \quad [5]$$

Future gas scenarios begin with the released 2018 figure of 184 gCO2e/kWh±2%, with four scenarios of 0%, 5%, 12.5 and 20% bio-mix injection beyond 2018 (carbon content of bio-methane injection = 5.13 gCO2e/kWh). ±2% uncertainty propagates forward in a linear manner since the gradient of the line that describes gas decarbonisation (expression 6 which describes natural gas graphs in Fig.1) is too small (i.e. -0.0028) for time (x) to have a major impact on the error size (ε) where y is the equivalent carbon content of gas supply (CO2e/kWh):

$$y_{ng} \pm \varepsilon = -0.0028x + 0.1903 \quad [6]$$

These combination of three electricity and 4 gas decarbonisation pathways combine to form 12 scenarios which captures the most probable breadth of policy-based decarbonisation commitment (Fig. 1).

5 Results and discussion

5.1 Model Calibration

Electricity data (recorded at 60s intervals) was logged on transformer substations of two towers and additionally in 20 apartments (i.e. clamp-on sensors). These were aggregated into hourly time steps to guide hourly model calibration. However the only practical way of collecting gas consumption (supplied to type 2 only) was manual recording at daily intervals (see next paragraph). Privacy and ethical reasons limited project team's data collection efforts to a maximum of 9 months. To further assess the characteristics of both building types and validate tower energy requirements, calibrated electricity and gas results are benchmarked against actual UK domestic energy consumption in the next section. Three type 1 towers are exactly identical in floor area, fabric composition and internal layout, and the same is true for the two type 2 towers. Clearly slight energy consumption variation existed between each set of tower types. However given that the purpose of the exercise here is the design of centralised energy solutions to meet the 'aggregated' demands of three type 1 or two type 2 towers (as opposed to perfect representation of a single tower), a single representative model per tower type was developed against actual data for each tower type (with variations between towers of the same type averaged to calibrate a corresponding representative model). Fig. 4 shows winter-time hourly electrical peak in type 2 towers that is 4 times larger than peak summer-time values due to the charging of night-time storage heaters. Type 1 towers (heated by decentralised gas boilers) have a winter-time hourly peak that are twice in magnitude to summer loads demonstrating a much smaller yet notable seasonal variation. The calibrated type 1 model over-predicted actual per tower electricity consumption by 5.8% and had hourly MBE and CV(RMSE) values of -6.2% and 17.9% respectively. The calibrated type 2 model over-predicted the actual per tower electricity consumption by 3.9% with MBE and CV(RMSE) values of -3% and 11.7% respectively. Model electricity predictions therefore fall within ASHREA guides for type 1 and 2 towers.

Fig. 4 - Fig. 6 and table 4

Natural gas is supplied to three type 1 towers to meet radiator-based central heating, DHW and gas cooking demands. Gas consumption proved to be the most difficult stream of data to collect and quantify as a variety of different gas meter types existed, of which two were instrumented by pulse-counting sensors, yet none produced data of sufficient quality and continuity to guide model calibration. In the absence of sufficient budget and time to support the deployment of non-intrusive gas monitoring equipment at tower level (i.e. clamp-on ultrasound sensors), and also given that the local distribution company was not in possession of adequate gas usage data, the most practical method proved to be manual daily gas meter recording (summarised in boxplot forms in Fig. 5). Prior to and post manual recordings, gas meter readings were taken to act as a validation reference point. A total of 11 apartment owners (4 one-bedroom and 7 two-bedroom units) recorded daily gas meter readings for 7 months. Fig. 6 outlines absolute model errors against actual gas consumption (derived using expression 3). Participants were encouraged to log daily values at 7pm each day, however time differences in manual data recording, variations in DHW use, stochastic cooking activities and heating habits create uncertainties that are difficult to capture in an implicit energy model. Examined at monthly time-steps and at apartment-level resolution, the largest absolute errors in simulated gas results are over-predictions of -29% and under predictions of +45% (table 4, underlined entries). Staying at apartment level, these errors are reduced to -14% and +19% when examined across the entire 7 months of data collection (final row, table 4). However at tower level (all apartment gas consumption aggregated) the model has an overall MBE value of 3.2% (with CV(RMSE) of 12.6%) across the 7 months of observation. Therefore high levels of stochastic noise in daily gas consumption made it impractical to create a model that achieves calibration criteria at apartment unit level. It is nonetheless possible and more practical to parameterise the model in order to predict results in line with calibration limits at tower level. Given that centralised energy solutions are to meet aggregate demands, type 1 model is considered calibrated as it can produce aggregate tower gas consumption results within the monthly acceptance limits of ±5% (MBE) and ≤15% (CV(RMSE)).

5.2 Benchmarking

Table 5 shows type 1 and type 2 predicted performance before and after retrofit, using calibrated model energy predictions with CIBSE 2016 Test Reference Year (TRY) weather file [58]. The latest release of CIBSE TRY files are the closest climatic representation of local weather characteristics over a medium-term horizon. Fig 7 benchmarks calibrated model results against 3 sets of temperature adjusted and area-weighted UK energy benchmarks derived from actual field measurements ([a]-[c]) and 2 sets of best practice standards ([d]-[e]). Variations in metered gas and electricity consumptions can be substantial (extremities of weighted UK household metered gas and electricity consumption were found to be 2 and 4 times the mean [59] respectively). Upgraded fabric (denoted by –R suffix in Fig. 7) refers to fabric cladding being applied externally to achieve U-Values outlined in table 1.

Table 5: Calibrated model output per block using CIBSE TRY 2016 weather files

		Type 1 (Gas boiler heating)		Type 2 (Storage heater)	
		Existing fabric	Upgraded fabric	Existing fabric	Upgraded fabric
Annual loads (kWh)	Total Gas	841,053	426,847	-	-
	Total Electricity	234,286	229,080	632,788 [1]	440,798
	Small power, pumps and lifts	234,286	229,080	116,265	105,064
	Heating	655,782	246,560	359,965	181,107
	DHW [2]	155,957	150,973	137,574	135,643
	Cooking [2]	29,314	29,314	18,984	18,984
	Thermal to power Ratio (%)	2.9	1.52	4.2	3.01

Notes:

[1] The proportion of electricity consumption that occurred at the time of low rates (i.e. 00:00 to 07:00 hrs) were 57% and 59% in two electrified towers, giving an average of 58% (from substation monitoring data).

[2] Both models calibrated to achieve DHW equal to 17% and cooking equal to 3% of the total annual household energy demand as reported in [60].

Medium empirical value for domestic thermal demand (i.e. DHW and heating) range from 86 kWh/m^2/year to 201 kWh/m^2/year. While this variation is inevitable given the diverse UK architype and microclimates, uncertainties in property sizes, fuel conversion efficiencies and metering accuracy result in a wider than expected spread. If retrofitting efforts were to deliver fastest results by identifying least cost route, more robust benchmarking figures are needed to enable the concentration of resources where best results can be achieved. Fig 7. Illustrates that type 1 with its existing fabric represents medium UK domestic thermal demand (as benchmarked by Ofgem [61]). If type 1 fabric is retrofitted (to values outlined in table 1), its thermal demand is reduced by 63% to near the EnerPHit threshold of 50kWh/m^2/K. Type 2 existing fabric U-value is 56% lower than type 1, hence it has a much lower existing heating and DHW benchmark of 75.4 KWh/m^2/yr. representing the lower bounds of UK domestic thermal demand. This is further reduced by 50% as a result of a fabric upgrade to meet the threshold defining zero carbon homes (i.e. 39 KWh/m^2/yr.). The existing case study towers therefore represent medium (type 1) to low (type 2) thermal demand densities when benchmarked against actual UK domestic portfolio reported in Fig. 7. With existing fabrics, type 1 represents medium power density (49.1 kWh/m^2/yr.) while type 2 has much lower electrify demand of around 24.3 kWh/m^2/yr. and represents lower power demands than previously reported.

Fig. 7

Footnotes for Fig 7:

[a] Measured energy consumption in local authority properties (n= 500-700 households) [59].

[b] DECC (Department of Energy & Climate Change) 2013 temperature adjusted UK average gas and electricity consumption [62]. Area-weighted for average UK domestic property size of 90m^2 [63]with 3% discounted to account for cooking as reported in [44](n= Nationwide).

[c] BRE (Building Research Establishment) stock characteristics of average UK household gas consumption [64], area-weighted and adjusted for cooking as per [b] (n= 7370 households).

[d] The EnerPHit standard - a Passivhaus best practice combined heating and cooling target for retrofit projects [65].

[e] Zero Carbon Hub 'combined heating and cooling' to benchmark a zero carbon flat [66].

[f] Ofgem (The Office of Gas and Electricity Markets) typical domestic consumption values in 2017 (similar treatment as [b])[61].

5.3 Techno-economic of retrofit options

The results in this section covers 22 separate retrofit scenarios that involve:

1- The impact of fabric renovation to values outlined in table 1.
2- Centralised natural gas CHP, GSHP or wood pellet biomass installation in existing towers.
3- Centralised natural gas CHP, GSHP or wood pellet biomass installation with fabric renovation.

Savings achieved by these retrofits are benchmarked against business-as-usual (where either gas boilers or night storage electric heaters continue to be used in type 1 and 2 towers respectively). These 22 retrofit scenarios are appraised across a 2020-2040 horizon that is represented by:

1- 12 primary fuel CO2e scenarios.
2- 14 future financial scenarios.

Given the large combination of scenarios and for brevity, the overall trends and main findings are presented in this section. Across 2020-2040 time horizon, items with a green infill (Fig. 8-10) illustrate retrofit solutions that are capable of delivering the UK's implicit 2020-2040 target CO2 reductions of 50.6% (see 2.2). With reference to Fig. 8, notable observations on retrofit CO2e reductions are:

- Sensitivity to future fuel decarbonisation: Retrofit option retains the smallest error bars (Fig 8) and in both building types decarbonises heating in line with UK decarbonisation targets. All other retrofit options remain sensitive to future fuel decarbonisation since it is necessary to include small top-up boilers to boost GSHP output of 55°C to 80°C (for legionella-free DHW storage) and reduction of CHP and Biomass plant cycling.
- CHP engines in the UK have been able to offer overall carbon savings by using a lower carbon content fuel (i.e. natural gas at 184 gCO2e/kWh in 2015) to 'displace' electricity with a much higher equivalent carbon (i.e. 463 gCO2e/kWh in 2015) while also offering thermal energy as a by-product. However this carbon saving potential will progressively be offset by the rapidly decarbonising nature of grid electricity given that their input fuel (natural gas) decarbonises at a much slower pace under 12 scenarios examined here. If electricity decarbonises to 50gCO2e/kWh by 2030, CHP engines become net carbon producers as early as 2022 (when replacing gas boilers in type 1) or 2021 (when replacing night storage heaters in type 2). Only if natural gas decarbonises to its maximum potential by a bio-mix of 20% (by 2032) and electricity decarbonises to its min of 100gCO2e/kWh in 2030 do CHP engines return a modest lifetime (2020-2040) operational carbon saving of 25 tonnes in type 1 towers (denoted by the upper error bar of column representing CHP retrofit in T1; Fig. 8). If natural gas CHP replaces night storage heaters it will become a net carbon generator regardless of fuel decarbonisation path (Fig 8. CHP in T2 and T2R). Note that fuel switching in type 2 results in large error bars that reflect the impact of cleanest of dirtiest future fuel carbon content scenarios.
- Regardless of decarbonisation paths, GHSPs have an overall positive carbon saving potential with most benefit realised in type 1 where they replace gas boilers. However they can only decarbonise the heating sector in line with UK 2020-2040 reduction target of 50.6% if they are combined with a fabric retrofit (denoted with a green infill in Fig 8). Note that the larger error bands observed in GSHP savings in type 2 is a product of top-up boiler operation creating sensitivity to decarbonisation pathways.

- A centralised biomass retrofit is the only option whereby the outlined UK 2020-2040 CO_2e reduction target of 50.6% is achieved with or without a fabric upgrade. The low carbon content of biomass (at a constant 13.2 gCO_2e/kWh across 2020-2040) returns the highest overall carbon saving potentials of all solutions considered.

Fig. 8 and Fig. 9

Fig. 9 illustrates Net Present Value of each retrofit option under moderate (Fig 9. a) or extreme (Fig 9. b) fuel price rises of 2% or 5.2% respectively. Observations on the economic feasibility of retrofit options are:

- When unsubsidised, CHP engine installation (when replacing gas boilers in type 1) is the only retrofit option that returns a positive NPV, whereas the unsubsidised NPV of all other retrofits is nearly equal to corresponding CapEx, meaning that very little of the upfront investment will be recovered from energy savings over the 20 year operation.
- Fig. 9 illustrates the main weakness of an incentive-driven retrofit market: while upgrading the building fabric reduces the size and CapEx of primary plants and offers additional fuel savings, in all cases NPV of CHP, GSHP and biomass boiler replacement is deteriorated (between 76% to 279%) when plant and fabric retrofits are combined. This is firstly due to the much larger project CapEx and secondly (and importantly) to the loss of subsidy-driven revenues as the building requires less heating (particularly notable in GSHP results). The market signal (encapsulated in NPV) therefore prefers plant replacement in an inefficient building fabric than a deep retrofit (plant and fabric).
- GSHPs present radically different results with and without current UK Government subsidy of 26¢/kWh of thermal output. This subsidy creates wide NPV sensitivity (reflected in a much wider whisker span) because the present economic value assigned to future subsidy-driven revenues (i.e. discount factor 'r') and also its reliance on a more expensive fuel. That is also why the most notable difference between NPV at 2% or 5.2% annual fuel price rise is felt by subsidised GSHPs.
- Subsidised biomass boiler (at 8.7¢ /kWh of heat output) retrofit carries a strong likelihood to generate lifetime revenues in both building types but is loss-making if combined with a fabric upgrade. An unsubsidised biomass retrofit cannot be self-financing under any future fuel price rise or discount factors.
- Compared to a moderate annual fuel rise of 2%, an aggressive rise of 5.2% helps subsidised biomass boilers and GSHP to be revenue generating under an uncertain future landscape.
- Future incomes from subsidies lead to a wider range of NPV uncertainty for biomass boilers and GSHP. Note how much larger boxplot and whisker spans result for these technologies when subsidies are taken into account. This is driven by the current value assigned to future revenues (i.e. discount factor 'r').

5.4 Carbon mitigation unit costs of retrofits benchmarked against CCS

While market economics rank assets on the basis of the greatest lifetime income generation capacity (i.e. higher NPV), a carbon-centred assessment is presented in this section by examining lifetime operational CO_2e that is saved per unitised upfront investment for a give asset. In doing so, assets can be ranked on their least-cost carbon saving potentials, which will allow comparative studies within and between multiple sectors (i.e. least cost decarbonisation routes in transport vs buildings). The lower and upper boundaries of CCS costs outlined in section 2.3 (US$25-143/t$CO_2$) can provide a benchmark for economic competitiveness of proposed retrofits if viewed as a carbon abatement investment. Fig 10 outlines how much upfront investment ($) is required for a tonne of CO_2e to be saved across 2020-2040 time horizon for assets examined in this work.

Fig. 10

Note that [1] whisker spans reflect both economic (future value of money represented by 'r') and future fuel decarbonisation uncertainties and [2] green boxplots identify options capable of delivering the mandated 50.6% CO_2e reduction against a business as usual baseline. The main findings from this figures are:

- A wide range of results is observed, with a notable rise in the cost of CO_2e mitigation when fabric upgrade is added to plant retrofit solution (denoted by R suffix).
- The largest uncertainties (i.e. wider whisker span) exist on a transition from distributed night storage (i.e. T2) to either centralised GHSP (Fig 10 a: Boxplots 11 and 12) or centralised biomass (Fig 10 a: boxplots 15 and 16). Recall that T2 represents UK's low thermal demand (75.4 kWh/m2/yr.) and retrofits result in smaller overall energy savings. This in turn increases monetary cost per tonne of carbon saved and exaggerates the span of uncertainty.
- If unsubsidised, the best retrofit carbon mitigation result is achieved by a transition from natural gas to bio-fuel with no fabric retrofit (median value = $201/tonne of CO_2e, see Fig 10 a; boxplots 5) and the least carbon competitive transition is switching from night storage to GSHP with a retrofitted fabric (median value = $3204/tonne of CO_2e, see Fig 10 a: boxplot 11). This is because T1 has [1] existing heating pipework and radiator system that reduces plant retrofit CapEx, and [2] a more carbon intensive nature of fuel (natural gas) and higher baseline heat demand (137.3 kWh/m2/yr.). Bio-fuel transition in T2 has carbon mitigation results that are 16 times more expensive than those of T1. This is because T2 has [1] no hydronic distribution pipework and heat terminals, [2] lower baseline heat demand (75.4 kWh/m2/yr.) and [3] a rapidly decarbonising fuel (electrified night storage heaters).
- If subsidised, zero CO_2e mitigation costs are observed for three (CPI=2%) or five (CPI=5.2%) retrofit decisions (Fig 10, boxplots with zero labels). These are transitions that become revenue generating schemes (i.e. positive NPV) via existing UK government subsidies.
- Additionally with an average fuel price rise (CPI=2%) a subsidised 'deep retrofit' (GSHP and fabric upgrade) is able to offer a median carbon mitigation cost of $201/tonne of CO_2e with lower uncertainty bands falling within CCS economics (Fig 10 a: boxplot 10). An excessive fuel price rise will result in 3 subsidised deep retrofits to achieve economics comparable to CCS (Fig 10 b: boxplot 10, 12 and 14).

This final two bullet points illustrate how with current UK government subsidies, deep retrofits in building clusters representing medium UK thermal demand (137.3 kWh/m2/yr.) are capable of delivering lifetime heating sector decarbonisation with economics that are as competitive as CCS.

5.5 Carbon taxation as a market guide

Fig 11 outlines the level of CO_2e taxation required to allow a full CapEx recovery of the retrofits considered (i.e. to achieve a NVP of zero). In order to gain a measure of perspective, IPCC ideal-economy respective lower and upper quartiles for CO_2e pricing (US$37-67/t$CO_2e$ in 2020 and US$127-305/t$CO_2e$ in 2050) are translated to equal linear annual increases (i.e. US$3/tCO2e(Q1) and US$7.95 /tCO2e(Q3)). The higher annual increment of US$7.95 /tCO2e inform the assessment of required level of carbon pricing to enable a retrofits NPV of zero (meaning retrofit assets are neither loss-making nor revenue generating). This results in smaller initial carbon prices but given a more aggressive annual rise generates market signals for low carbon technology adaption. Main observations to note are:

- Under a moderate annual fuel price rise (i.e. CPI= 2%), a plant only transition from distributed natural gas boilers (T1) or electrical night storage heating (T2) to subsidised GSHP or biomass require no or modest carbon tax (Fig 11 a-b: boxplots 5,7,13 and 15). The level of carbon tax is further reduced at a CPI of 5.2% which represents an excessive annual fuel price rise (Fig 11 c-d: boxplot 6). However in the absence of low-carbon heating subsidies, none of the proposed retrofits will fully recover their CapEx under the proposed 2020-2040 IPCC carbon prices.
- The best unsubsidised result for individual gas boiler heating (T1) belongs to a transition to centralised biomass. Under the median case (representing median point on economic and carbon uncertainties discussed earlier) biomass installation fully recovers its CapEx under a 2020 carbon taxation of US$111/tCO2e rising to US$291/tCO2e in 2040 (Fig 11 a-b: boxplot 9). Transitioning to centralised biomass also produces the best unsubsidised results from a baseline of decentralised night storage heating (T2) where the biomass installation fully recovers its CapEx with a 2020 carbon taxation of US$280/tCO2e rising to US$734/tCO2e in 2040 (Fig 11 c-d: boxplot 11).
- Much larger error bands exists on T2 results emanating from the more uncertain nature of future electricity carbon content. Wider range of future CO2e content of electricity also translates into large error bands on GSHP results.
- If unsubsidised, deep retrofits (fabric and plant upgrade) have median case carbon tax requirements ranging from US$605-1665/tCO2e in 2020 to US$1586-4366/tCO2e in 2040. These are excessively high and impractical figures given for instance that the existing EU emission trading system carbon taxation is around US$23/tCO2e, or UK's 2020 carbon price is set at around US$38.78/tCO2e for its power sector. In particular in T2 towers which have an existing low thermal demand (75.4 kWh/m^2/yr.) and no hydronic distribution, recovering the CapEx of a deep retrofit via carbon taxation results in extremely high figures.

Fig. 11

A wide range of results needed to be presented in this section in order to support carbon tax assessment, thermal demand and CCS benchmarking that against an uncertain techno-economic landscape increases the complexity of analysis. The conclusion section summarises the most notable findings.

6 Conclusion

CO_2 remains the most important anthropogenic radiative forcing agent and capping (and reversing) cumulative CO_2 emissions in all sectors of economy remains a global priority. Deep decarbonisation of the economy is principally underwritten by economic investment. The uncertain carbon content of fuel and economic landscape across 2020-2040 propagates into substantial uncertainty bands (and hinders conclusive results) in the case study presented in this work, with the largest uncertainties occurring in a transition to GSHP. Narrowing this span of uncertainty is only possible with [1] a firm commitment to more specific electricity and natural gas decarbonisation targets and [2] a more focused definition of time value of money (i.e. 'r') for projects aimed at heating decarbonisation. More specific findings of this work can be summarised as below:

1. With no government subsidies, 20,303 m^2 of gross domestic space (i.e. three type 1 towers containing 265 apartments) heated by individual gas boilers with thermal demand representing UK average (137 $kWh/m^2/yr$) can achieve lifetime carbon mitigation unit costs of 201 US$/tCO2e via a transition to centralised biomass. This figure is only 40% higher than the upper threshold of CCS (143 US$/tCO2e). This illustrates that despite large CapEx and uncertainties regarding returns on investment, economies of scale of building clusters with above average thermal demand can offer retrofit CO2e mitigation platforms that can compete economically with the best available decarbonisation tools (i.e. CCS).
2. With no government subsidies, 13,535m^2 of gross domestic space (i.e. two type 2 towers containing 174 apartments) heated by night storage heaters characterising low UK thermal demand (75.4 $kWh/m^2/yr$) can achieve the best carbon mitigation cost (554 US$/tCO2e) via a transition to centralised biomass.
3. The two previous points illustrate that identifying the most competitive platforms for heating decarbonisation requires: [i] characterisation of thermal and electrical demands of existing portfolio (a difficult task particularly with natural gas usage as encountered and outlined in section 5.2). Available empirical data lacks corresponding knowledge of property size that impairs efforts to benchmark case-study buildings and determine least cost routes to decarbonisation of building sector, [ii] masterplannig of centralised low carbon energy systems, otherwise an unguided market will be dominated by isolated decisions opting for legacy solutions (i.e. replacement gas boilers).
4. Within the boundaries of 12 future carbon content and 14 economic scenarios, the highest lifetime carbon savings were achieved by centralised biomass boilers and GSHP respectively (both loss-making investments if unsubsidised but able to recover their CapEx and further generate income with current UK CPI-linked subsidies of 8.7¢ and 26¢ per kWh of heat output respectively). Fabric retrofit offers the 3rd highest carbon saving potential yet as a result of its large CapEx (and unsubsidised nature) was a loss-making investment. Across an unsubsidised future market condition, CHP is the only retrofit that can maintain a positive NPV when replacing gas boilers in type 1 towers and at discount rates of below 5.5% while delivering carbon savings only if natural gas contains 20% biofuel by 2032. However natural gas CHP engines become net carbon producers when replacing electrical night storage heaters (type 2 towers) under all future scenarios examined.
5. Although current UK Government incentives for low carbon heating solutions can help a loss-making investment to generate revenue, subsidy-driven economics is flawed as it prefers a plant-only upgrade in energy-intensive buildings and returns less attractive results for deep retrofits involving

fabric and plant upgrades. To deliver the implicit 50.6% UK carbon reduction target across 2020-2040, a centralised biomass retrofit (plant only) or a deep retrofit (both plant and fabric) in both tower types has to be undertaken (involving either centralised GSHP or biomass). Deep retrofits can reduce the heating energy intensity of both tower types to meet the threshold that define a zero carbon home (i.e. 39 $KWh/m^2/yr$ – see 2.1).

6. When compared to a moderate annual fuel price rise of 2%, an excessive annual rise of 5.2% was not able to radically change the techno-economics of retrofits considered in this work. This illustrates the prominence of CapEx (and not the operating costs) as the sole determinant of economics of retrofits.
7. Without current UK subsidies, the magnitude of carbon taxes that can enable full CapEx recovery of retrofit solutions were disproportionate, with the most competitive result being for a plant only transition to centralised biomass (replacing individual gas boilers in type 1) requiring US$111/tCO2e in 2020 (rising to US$291/tCO2e in 2040) and the best deep retrofit result being for a centralised biomass and fabric upgrade (replacing individual gas boilers in type 1) requiring US$448/tCO2e in 2020 (rising to US$1174/tCO2e in 2040). These figures are well in excess of IPCC 2020 lower and upper quartile figures of US$37/tCO2e and US$67/tCO2e (translating to US$97/tCO2e and US$226/tCO2e in 2040). While carbon pricing may play a polluter-agnostic and complimentary policy role to help investment decisions and limit conventional technologies (gas boilers) becoming stranded assets, substantial part of heating sector decarbonisation needs to be funded via other mechanisms.

Decarbonisation of heating is pivotal to achieving national and international carbon targets. If left to an unguided market, the retrofit sector will continue to be dominated by legacy technologies. Legacy HVAC plants have a much longer asset life than emitters such as cars and will result in carbon lock-in for the rest of their working lives. This can only be prevented by funding and masterplannig of integrated low-carbon energy systems at and beyond district levels.

7 Limitations

The non-monetary value of improved occupant comfort in a thermally efficient building or the rebound effects of lower fuel costs were not considered. Collecting high quality natural gas consumption data remained the biggest challenge in this work which effects precise calculation of heating and DHW use and benchmarking. The useful lifespan of fabric retrofit is more than 20 years yet it was assumed so to enable a comparison with other retrofit solutions over 2020-2040. While CO2 remains the most notable and the main constituent of building-related emissions, Kyoto protocol identifies 6 gases with even a larger list proposed by the Intergovernmental Panel on Climate Change [67] which while outside the scope of this work may provide the platform for a more rigorous building related operational and ultimately life-cycle emissions reporting which in its fullest form necessitates treatment of embedded carbon too.

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Appendix A: GSHP considerations

Geologically both sites rest on 1-2m (at places up to 4.5m) of well-compressed and stiff brown silty clay (with well dispersed pebbles) and Devensian till (tough, over-consolidated, grey or brown sandy clay with abundant pebbles and cobbles) above layers of sandstone, mudstone, limestone and lignite (down to 30m). These superficial deposits are underlain by well compressed sedimentary bedrock variety that in the UK is referred to as Pennine Middle Coal Measures (mudstones, siltstones, sandstones and coals with some mapped sandstone horizons) which at places also contain metal [68]. This poses little to moderate cable percussion (or shell and auger) drilling difficulties to the target depth of 110m considered for this work. Soil condition has generally been reported as damp and although water levels are subject to seasonal and tidal variation in the wider area, drilling has historically encountered water tables roughly between 3-4m below ground level at type 1 tower site and at 1.4-2.4m below ground level for type 2 tower site (both with good ground water flows). Concrete-lined boreholes in this soil type are classified to offer specific heat extraction rates between 40 to 80 W/m under 2400 hours of operation [69], hence 60W/m is used to size the geothermal array. Additionally a local weather station (0.5km from type 1 and 1.4 km from type 2 towers) provided 5 years of accumulated air temperature, from which a mid-depth soil temperature of 10.5°C was derived as given by formula A1 which is an empirical derivation suggested for Scandinavia [70]:

$$T_m = T_0 + 0.02 \times h \qquad \text{[A1]}$$

Where T_m is mean ground temperature (°C), T_o is annual mean air temperature (°C), h is depth below the ground surface (m). Based on a 5 year average air temperature of 9.54°C, soil temperature at a mid-borehole depth of 55m would be 10.50°C, and based on a 2K thermal approach (or pinch effect) specific to the heat exchanger manufacturer data, GSHP evaporate side flow and return temperatures for a 4.5K ΔT would stand at 4°C-8.5°C. These values, together with GSHP SPF value of 3.5 are used to derive the geothermal array flow rates and additional pumping duties. Using an average annual air temperature of 9.54°C as that of the incoming cold mains, and a DHW delivery temperature of 60°C, the GSHP will fulfil all space heating and approximately 60% of DHW duties with the rest met by top up gas boilers.

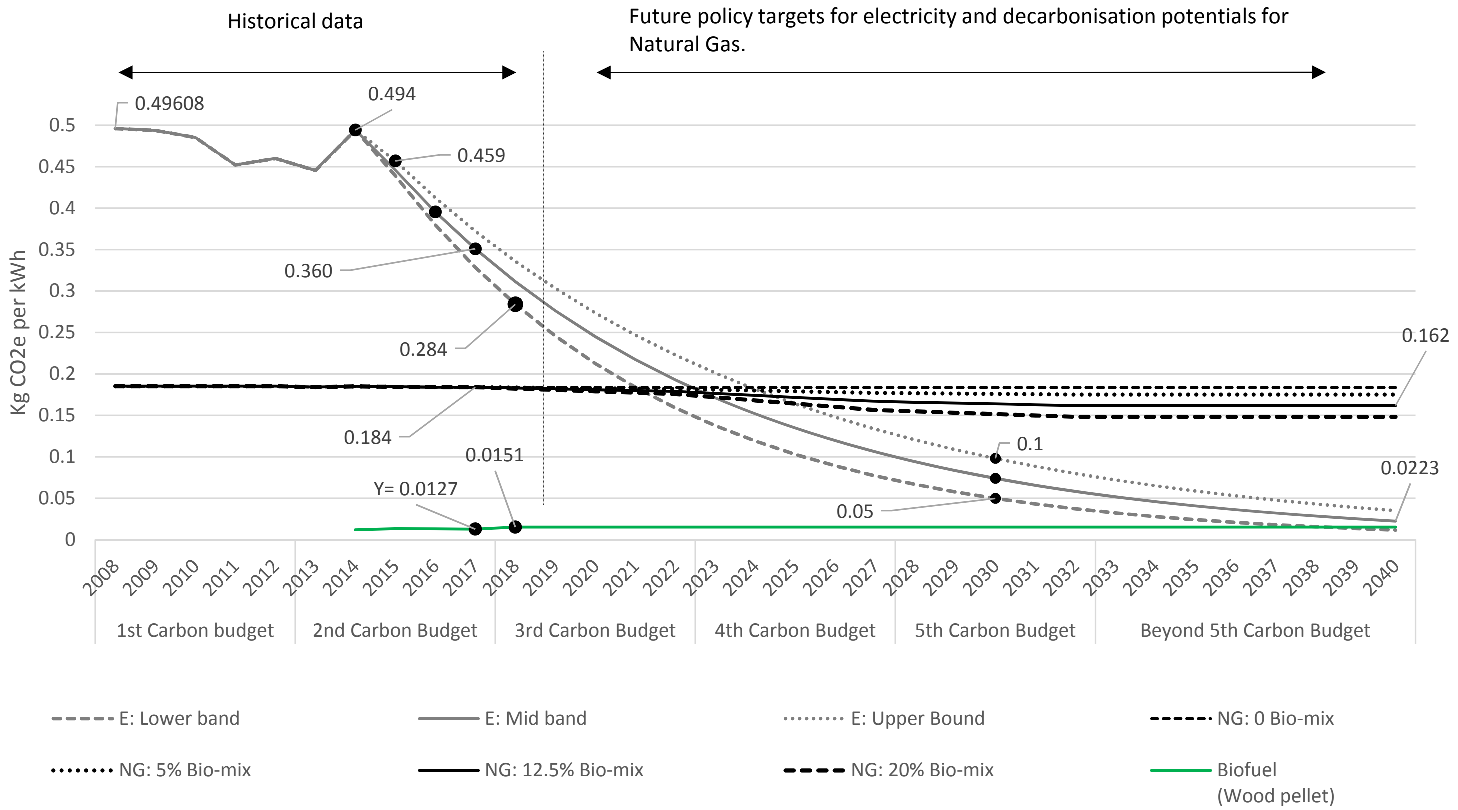


Fig 1: Historical trends and future decarbonisation paths for UK grid electricity (aiming for 50-100 gCO2e/kWh by 2030) and natural gas (0% to 20% bio-mix by the end of 5th carbon budget). E: Grid electricity, NG: Natural Gas.

Fig 2: Left: three type 1 towers with natural gas supplies and (right) two electrified towers with night storage heaters (type 2).

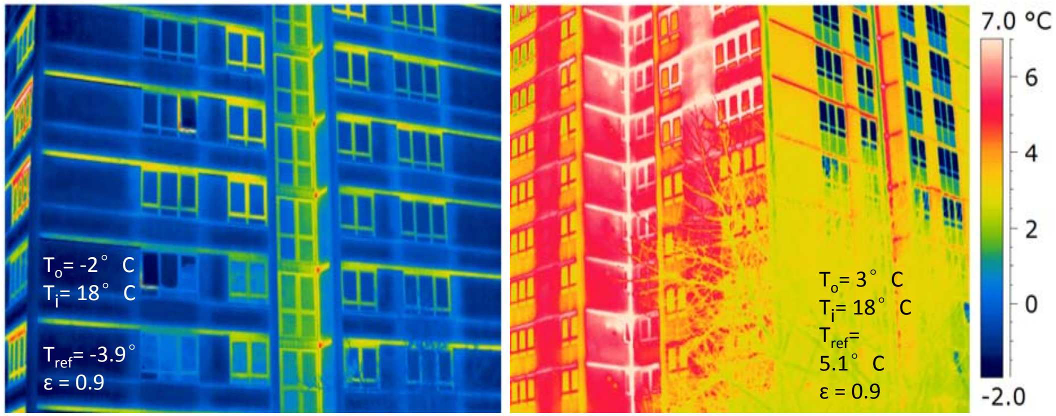
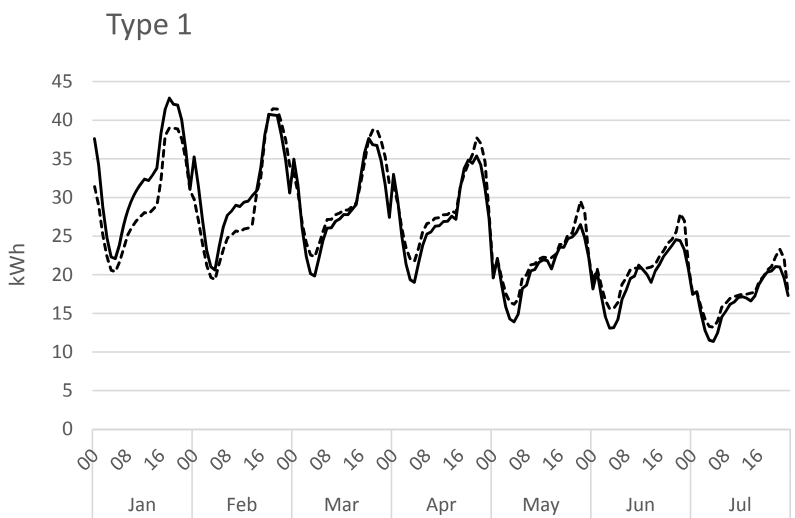
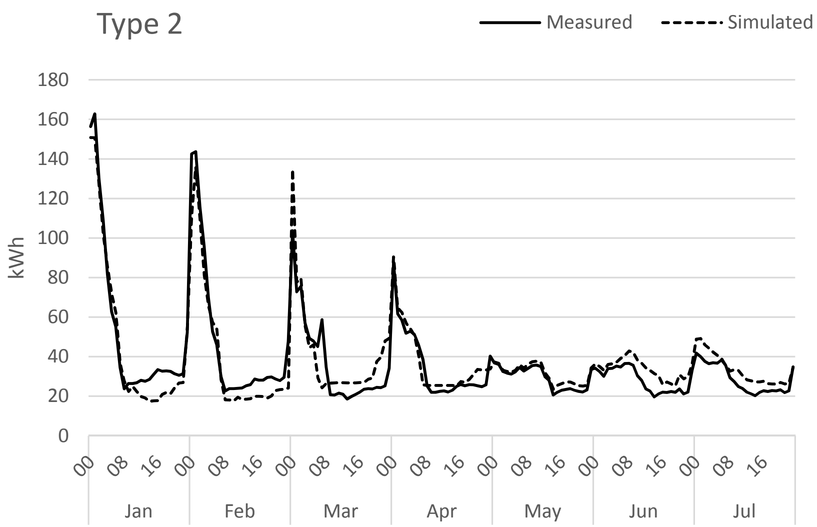


Fig 3: Cold bridging caused by floor slabs in both tower types: ε: surface emissivity, Tref: Reflected temperature, To/Ti: outside /inside temperatures.





	Measured	Simulated	
i	5088	5088	hrs
Min	11.4	13.2	kWh
Max	42.9	41.5	kWh
Ave	25.4	25.5	kWh
σ	7.4	6.7	kWh
∑	122,103	129,230	kWh
MBE	-6.2%		
CV(RMSE)	17.9%		

	Measured	Simulated	
i	5088	5088	hrs
Min	18.5	17.4	kWh
Max	162.8	150.8	kWh
Ave	37.1	38.1	kWh
σ	25.6	24.4	kWh
∑	188,384	196,082	kWh
MBE	-3.0%		
CV(RMSE)	11.70%		

Fig 4: Measured vs Simulated results for type 1 and 2 towers (line graph averaged at monthly and hourly intervals for visualisation)

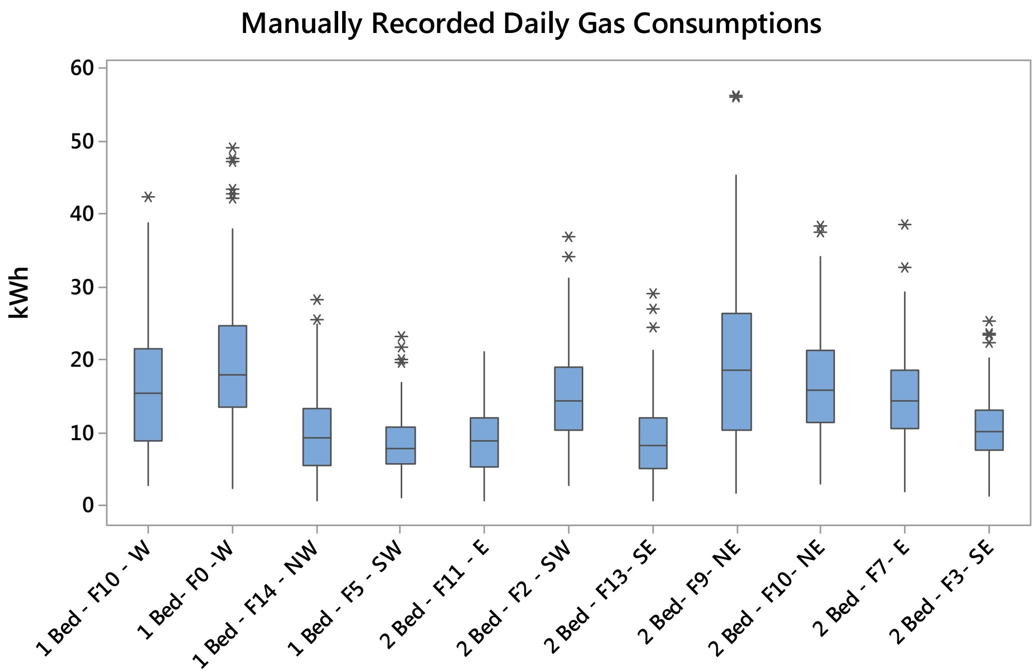


Fig 5: Boxplots of daily gas consumption results for 11 type 1 apartments (label key: bedroom numbers, floor level, Orientation)

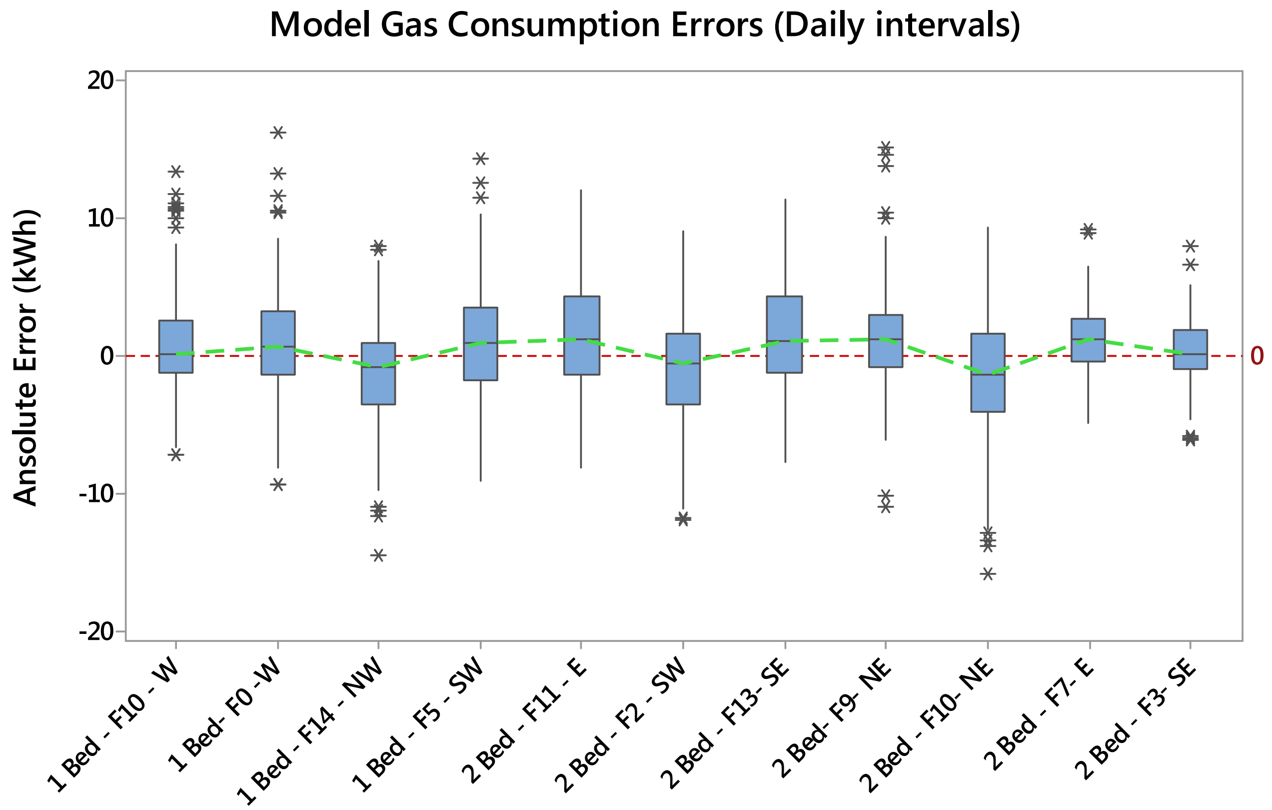
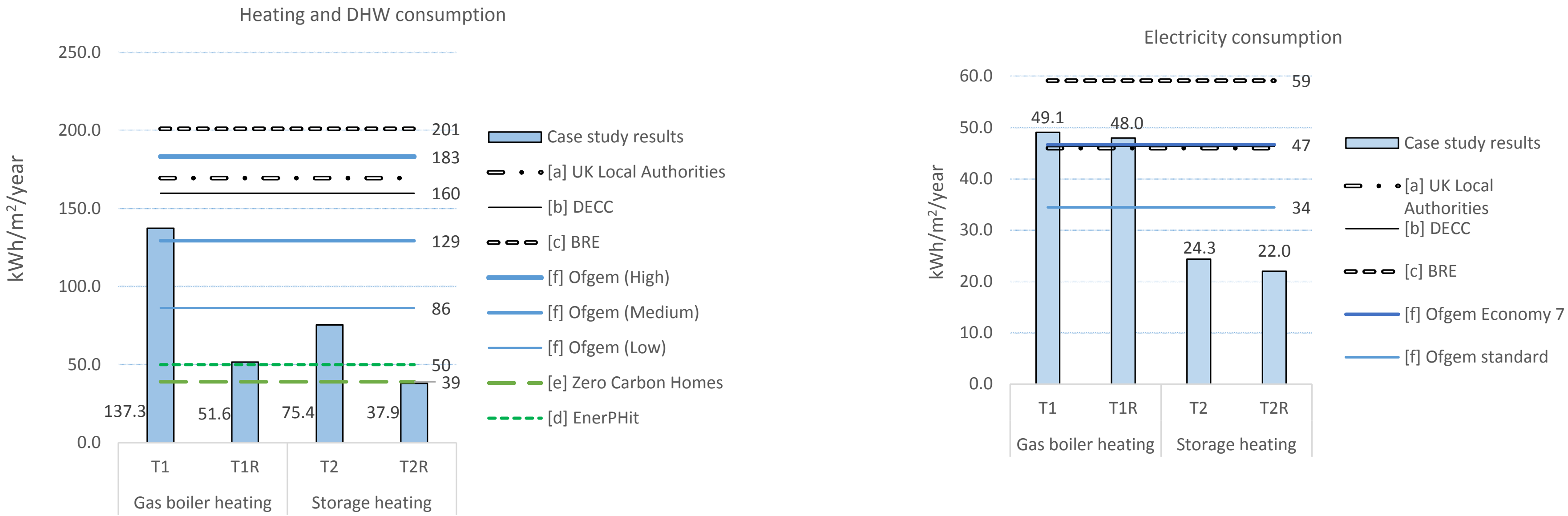


Fig 6: Boxplot of model errors with median connect line (labels: bedroom numbers, floor level, Orientation)

	1 Bed				2 Bed						
	F10 W	F0 W	F14 NW	F5 SW	F11 E	F2 SW	F13 SE	F9 NE	F10 NE	F7 E	F3 SE
Jan	6%	2%	-4%	14%	7%	1%	11%	0%	-19%	5%	-6%
Feb	7%	5%	-15%	7%	9%	-8%	19%	7%	-1%	6%	6%
Mar	5%	0%	-13%	-2%	9%	-4%	20%	10%	-10%	1%	2%
Apr	-1%	6%	-18%	21%	17%	-7%	9%	10%	-10%	10%	6%
May	0%	5%	-15%	9%	26%	-4%	22%	8%	-18%	13%	1%
Jun	15%	13%	-13%	13%	9%	-8%	**45%**	7%	-13%	10%	5%
Jul	11%	13%	-15%	33%	31%	**-29%**	16%	4%	-6%	21%	14%
7 month MBEs at single apartment level	5%	5%	**-14%**	11%	14%	-6%	**19%**	7%	-11%	8%	3%

7 month MBE at aggregated apartment level	3.2%

Table 4 : Type 1 model gas prediction MBE values



Footnotes:

[a] Measured energy consumption in local authority properties (n= 500-700 households) [59].

[b] DECC (Department of Energy & Climate Change) 2013 temperature adjusted UK average gas and electricity consumption [62]. Area-weighted for average UK domestic property size of 90m^2 [63]with 3% discounted to account for cooking as reported in [44](n= Nationwide).

[c] BRE (Building Research Establishment) stock characteristics of average UK household gas consumption [64], area-weighted and adjusted for cooking as per [b] (n= 7370 households).

[d] The EnerPHit standard - a Passivhaus best practice combined heating and cooling target for retrofit projects [65].

[e] Zero Carbon Hub 'combined heating and cooling' to benchmark a zero carbon flat [66].

[f] Ofgem (The Office of Gas and Electricity Markets) typical domestic consumption values in 2017 (similar treatment as [b])[61].

Fig 7:Benchmarking of case-study energy model TRY simulation results against existing field data and best practise guidelines
Key: T1/T2: Type1/2 towers. R Suffix: Retrofitted fabric (to part L requirement, see table 1).

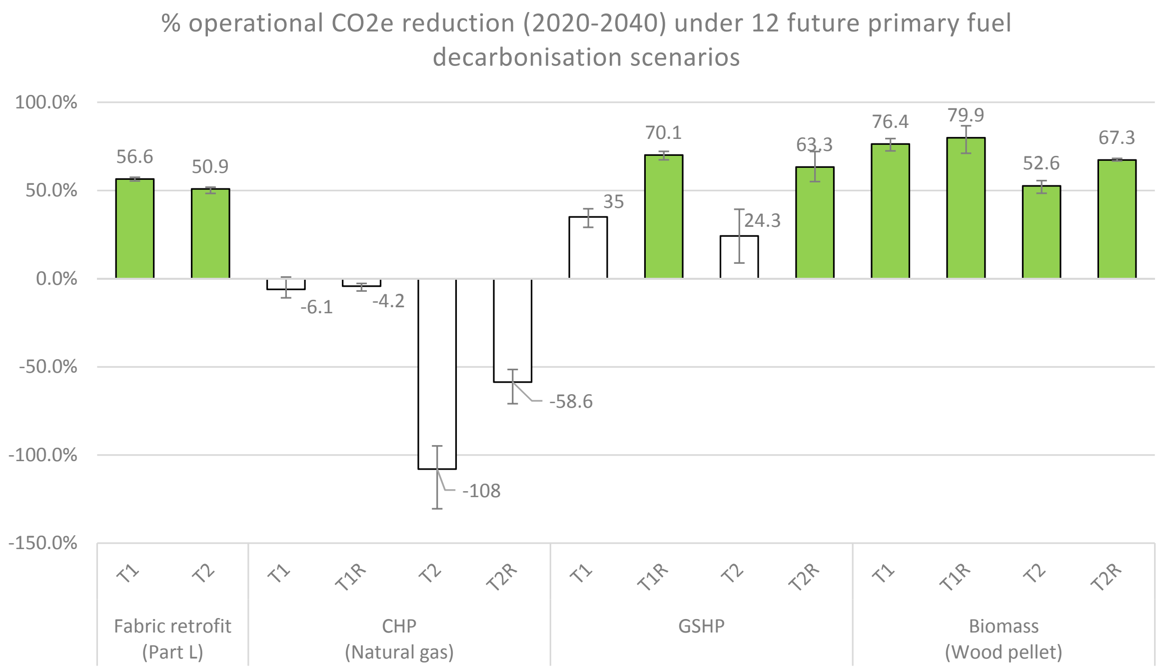


Fig 8: Percentage lifetime CO2e savings of retrofit solutions. Green columns: CO2 savings ≥50.24% (see section 2.2). Negative values: Retrofits generating (not saving) carbon against a business as usual scenario. Data labels (and error bars): medium value (and min to Max range of results) for each retrofit option as a function of 12 future primary fuel carbon content scenarios.
Key: T1/T2: Type1/2 towers. R Suffix: Retrofitted fabric (to part L requirement, see table 1).

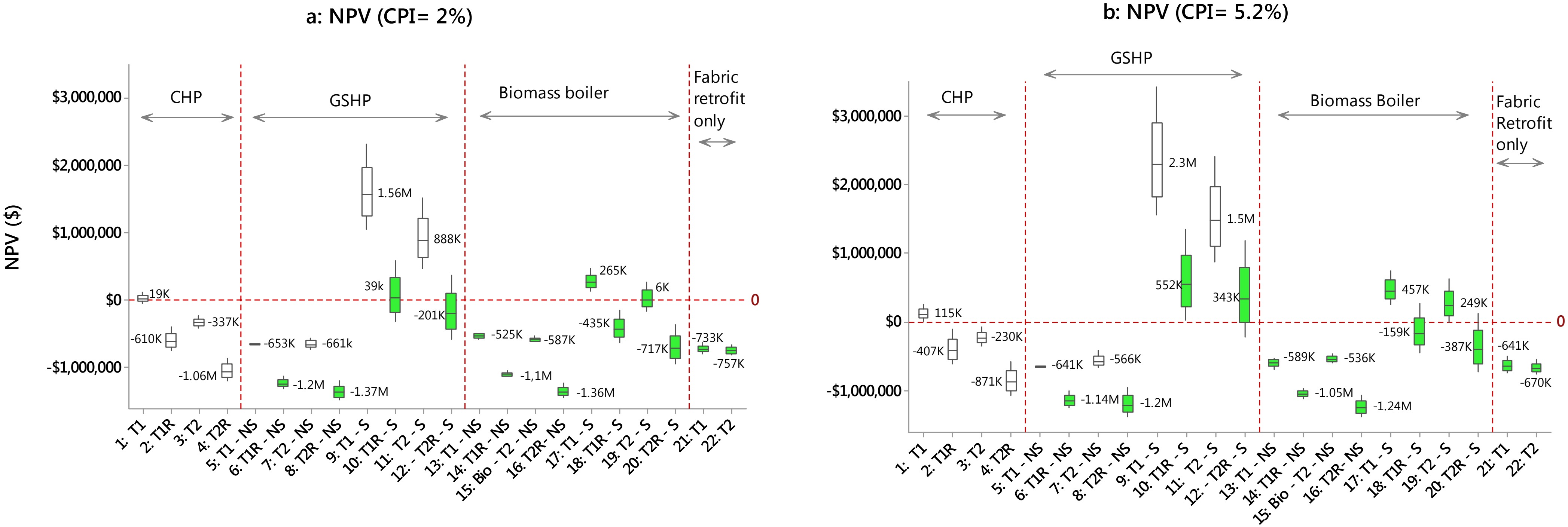


Fig 9: Retrofit NPV with whisker span representing the range of discount rate (i.e. r = 2%-8%). Green boxplots: Solutions with 50.6%+ CO_2e reduction across 2020-2040. Data labels: Median value. CPI (consumer price index) reflects a moderate (2%) or aggressive (5.2%) annual fuel price rise.
Key: T1/2: Type1/2 towers. R Suffix: Retrofitted fabric (to part L requirement, see table 1). S: Subsidised; NS: Not subsidised.

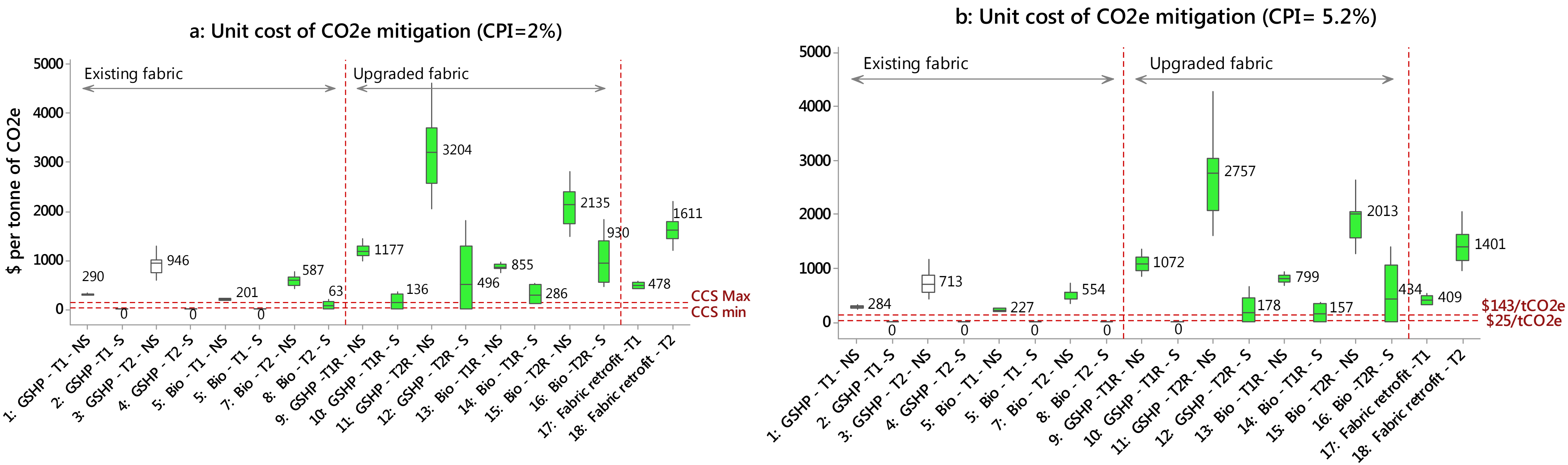


Fig 10: Unitised carbon mitigation cost of retrofits benchmarked against CCS unit costs. Whisker spans represent [a] variations in time value of money (r) and [b] future fuel decarbonisation uncertainty. Green infills: retrofits achieving a 50.6% CO_2e emission reduction. Data labels: Median value. CPI (consumer price index) reflects a moderate (2%) or aggressive (5.2%) annual fuel price rise.
Key: T1/2: Type1/2 towers. R Suffix: Retrofitted fabric (to part L requirement, see table 1). S: Subsidised; NS: Not subsidised.

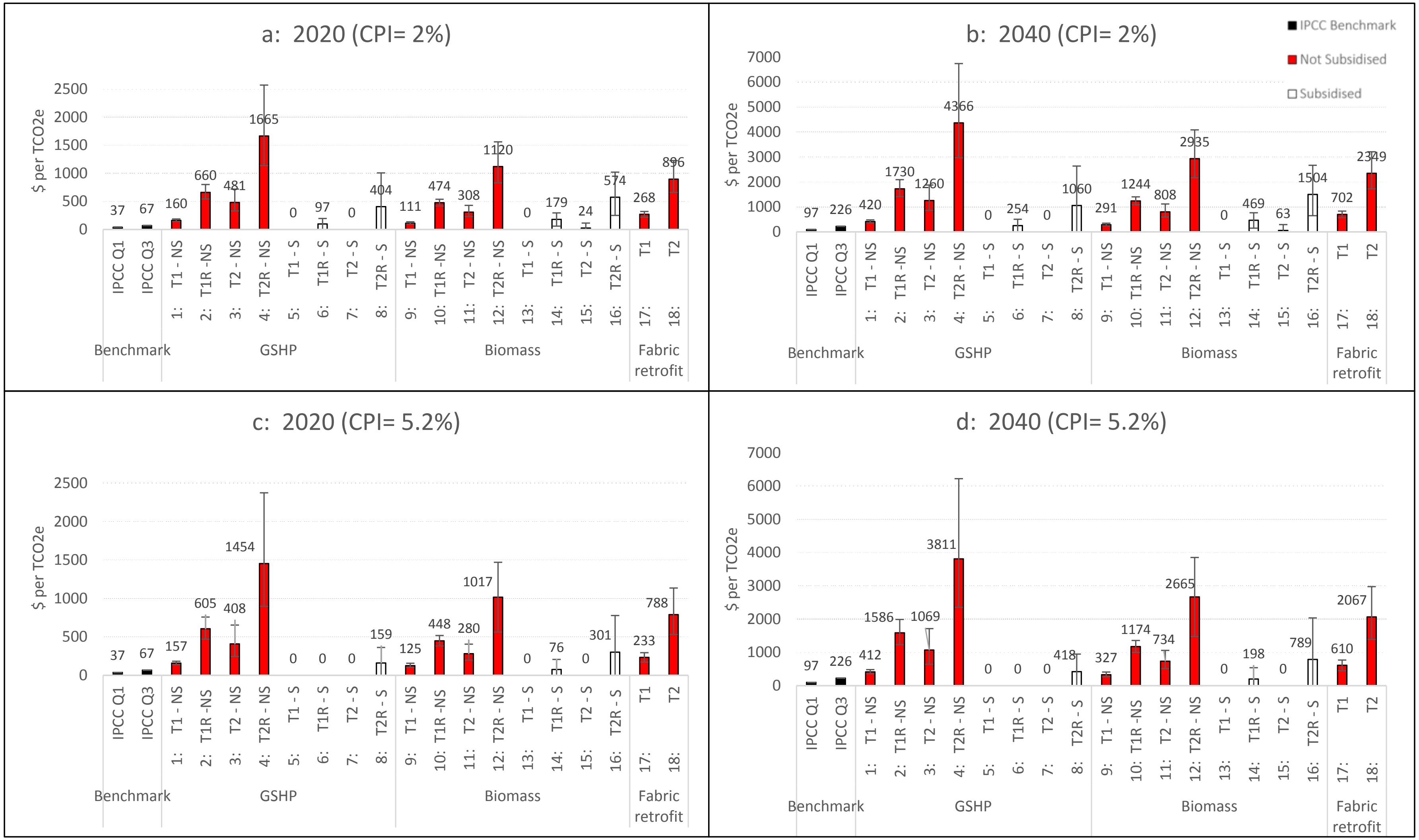


Fig 11: Carbon tax (US$/tCO2e) required for full retrofit CapEx recovery. Error bars represent [a] variations in time value of money (r) and [b] future fuel decarbonisation uncertainty. Data labels: median value. CPI (consumer price index) reflects a moderate (2%) or aggressive (5.2%) annual fuel price rise.
Key: T1/T2: Type1/Type 2 towers; R Suffix: Retrofitted fabric. S: Subsidised; NS: Not subsidised